Air Quality Permitting Statement of Basis

March 25, 2005

Tier I Operating Permit No. T1-020108

Rathdrum Power, Rathdrum, ID

AIRS Facility No. 055-00045

Prepared by:

Ken Hanna, Permit Writer
AIR QUALITY DIVISION

FINAL PERMIT

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Acronyms, Units, and Chemical Nomenclature

AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
CAM	Compliance Assurance Monitoring
CEMS	continuous emissions monitoring systems
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
gr	grain
HAPs	Hazardous Air Pollutants
Hg	mercury
HRSG	heat recovery steam generator
hr/yr	hours per year
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometer
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
MACT	Maximum Available Control Technology
mm	millimeters
MMBtu	million British thermal units
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	Nation Emission Standards for Hazardous Air Pollutants
ng/J	nanograms per joule
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 micrometers or less
ppmvd	parts per million by volume on a dry basis
PSD	Prevention of Significant Deterioration
PTC	permit to construct
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SM	synthetic minor
SO_2	sulfur dioxide
T/yr	tons per year
TAPs	toxic air pollutants
UTM	Universal Transverse Mercator
VOC	volatile organic compound

Public Comment / Affected States / EPA Review Summary

A 30-day public comment period for the Rathdrum Power Draft Tier I operating permit was held from July 26, 2004 through August 25, 2004 in accordance with IDAPA 58.01.01.364, *Rules for the Control of Air Pollution in Idaho*. During this comment period, DEQ became aware of the revision to 40 CFR Part 60 Subpart GG that was issued by the EPA as a final rule on July 8, 2004. To ensure the Tier I Operating Permit is consistent with the revised EPA rules, it has been revised accordingly. In particular, Draft Tier I Permit Conditions 3.16, 3.19, 3.25 and 3.26 were revised.

IDAPA 58.01.01.008.01, defines *affected states* as, "All states: whose air quality may be affected by the emissions of the Tier I source and that are contiguous to Idaho, or that are within 50 miles of the Tier I source."

A review of the site location information included in the permit application indicates that the facility is located within 50 miles of a state border. Therefore, the states of Washington and Montana were provided an opportunity to comment on the draft Tier I operating permit.

After the public comment period, EPA was sent the proposed operating permit and the statement of basis for their 45 day review period. EPA did not provide any comments on the permit.

1. PURPOSE

The purpose of this memorandum is to explain the legal and factual basis for the Tier I operating permit in accordance with IDAPA 58.01.01.362, *Rules for the Control of Air Pollution in Idaho.*

DEQ has reviewed the information provided by Rathdrum Power regarding operations of the electric power generation facility located near Rathdrum, Idaho. This information was submitted based on the requirements to submit a Tier I operating permit in accordance with IDAPA 58.01.01.300.

2. SUMMARY OF EVENTS

On April 11, 2002, DEQ received the Tier I operating permit application from Rathdrum Power for the electric power generation facility. The application was determined to be administratively complete August 8, 2002.

3. BASIS OF THE ANALYSIS

The following documents were relied upon in preparing this memorandum and the Tier I operating permit:

- Tier I operating permit application, received April 11, 2002.
- Permit to Construct No. 055-00045 as last modified on October 12, 2004
- Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, January 1995, Office of Air Quality Planning and Standards, EPA
- Guidance developed by the EPA and DEQ
- Title V permits issued by other jurisdictions.

4. FACILITY DESCRIPTION

General Process Description

The project includes one General Electric (GE) advanced gas turbine engine with supplemental firing capability in the form of "duct burners." The project operates in combined-cycle mode such that the hot turbine exhaust gases will be discharged to the heat recovery steam generator (HRSG) to create steam that will be used to drive the steam turbine. The turbine and duct burners are fired with natural gas only and emissions are exhausted through a 150-foot tall, 18-foot diameter stack. The project is designed to produce approximately 270 MW electricity. The GE gas turbine will produce approximately 160 MW; the HRSG is capable of generating approximately 90 MW without duct burner operation and 110 MW when the duct burner does operate. To minimize NO_x emissions, the GE gas turbine is equipped with dry low-NO_x combustion technology with guaranteed, uncontrolled NO_x emissions of 9 ppmvd. Within the HRSG, a selective catalytic reduction (SCR) system is installed to further control NO_x emissions and an oxidation catalyst is installed to control CO emissions (from both the turbine and duct burners). The steam turbine system also includes a condenser with a mechanical draft-cooling tower. An integrated, microprocessor-based distributed control system is installed for plant control, data acquisition, and data analysis.

The following is a list of the sources at the facility:

Gas Turbine:	GE PG7241(FA), 8000 hr/yr, 1517.9 MMBtu/hr rated input
Duct Firing:	230 MMBtu/hr, natural gas, 2000 hr/yr
Auxiliary Boiler:	17 MMBtu/hr, natural gas, 5000 hr/yr
Fuel Preheater:	4 MMBtu/hr, natural gas, 8000 hr/yr
Emergency Generator:	550 horsepower, diesel, 500 hr/yr
Fire Water Pump:	185 horsepower diesel, 500 hr/yr
SCR:	at least 62% NO_x control efficiency, with ammonia injection, 3-year catalyst life typical
Oxidation Catalyst:	at least 27% CO control efficiency, 3-year catalyst life typical

Facility Classification

The facility is not classified as a major facility in accordance with IDAPA 58.01.01.008.10 for Tier I permitting purposes. Also, the facility is not major as defined in IDAPA 58.01.01.006.55. However, the Rathdrum Power facility meets the definition of a Tier I source as given by IDAPA 58.01.01.006.104 (b and d), since it is subject to NSPS standards under 40 CFR 60 and it is a Phase II acid rain source. The facility is a designated facility as defined in IDAPA 58.01.01.006.27 (fossil-fuel fired steam electric plant), but it is not subject to PSD permitting requirements because the facility's potential to emit is less than 100 T/yr. The AIRS facility classification is SM.

This facility is a combined-cycle, gas-turbine, power generation facility, Standard Industrial Classification code 4911. For purposes of applying EPA's Compliance Monitoring Strategy (CMS), April 2001 Draft, Rathdrum Power is classified as a synthetic minor source that emits or has the potential to emit at or above 80% of the Title V major source threshold (SM-80). As such, the facility is subject to a full compliance evaluation at least once every five years and also to partial compliance evaluations, investigations, and inspections as described in the draft CMS.

Area Classification

The facility is located in Kootenai County, AQCR Region No. 62, which is classified as an attainment or unclassifiable area for all federal and state criteria pollutants. There are no Class I areas within 10 km of the facility.

Permitting History

The following information was derived from a review of the archived source file and the active source file. This documentation is intended for information use only:

October 29, 1999	Rathdrum Power LLC was issued a modified PTC for the initial construction of a 270 MW combined cycle facility.
February 27, 2004	A draft copy of the Tier I operating permit and statement of basis were issued to Rathdrum Power LLC.
June 10, 2004	A draft copy of the Tier I operating permit and statement of basis were issued to Rathdrum Power LLC.
October 12, 2004	Rathdrum Power LLC was issued a modified PTC

Emissions Description

Emission estimates from the gas turbine/HRSG stack are based on the gas turbine manufacturer's performance specifications. Average emission rates are based on an ambient temperature of 49°F, which is the average annual temperature in the area. The maximum emission rates are based on an ambient temperature of 0°F, which is used to represent winter conditions. As in the original analysis for this facility, the emission rates used for the permit analysis are all based on the maximum emission rate at 0°F for both the short-term (pound-per-hour) and the long-term (ton-per-year) emission rates. The exception is the NO_x and CO long-term emission rates, which are based on the average emission rate at 49°F, as was done in the original analysis, which is appropriate for the annual estimate. The estimated emissions are shown in Table 1 below. Included are values for the gas turbine alone, the turbine with duct firing, other natural gas-fired equipment (which refers to the auxiliary boiler and the fuel preheater), and total facility emissions (which refers to the turbine, duct firing, auxiliary boiler, fuel preheater, emergency generator, and diesel fire water pump). Note that operation of the diesel-fired emergency generator and fire water pump are limited by a permit condition that allows no more than 500 hr/yr of operation; this inherently limits emissions from those sources so that the total facility emissions of NO_x and CO will be maintained below 100 T/yr. Actual operation of the diesel engines is projected to be much less than 500 hr/yr.

Table 1. CONTROLLED EMISSIONS ESTIMATES

Source Description	SO_2		NO_x		CO		VOC		PM / PM_{10}	
	lb/hr	T/yr	lb/h	T/yr @ 49°F	lb/hr	T/yr @ 49°F	lb/hr	T/yr	lb/hr	T/yr
Gas turbine w/o duct firing	2.57	10.3	22.8	85.1	21.2	78.8	1.04	4.2	9.0	36.0
Gas turbine w/duct firing	2.70	10.4	29.8	92.1	34.6	92.3	1.50	4.7	10.7	37.7
Other natural gas-fired equipment	0.015	0.04	2.0	5.5	2.0	5.6	0.05	0.14	0.19	0.6
Emergency diesel engines	0.4	0.2	4.9	1.4	1.5	0.4	0.5	0.1	0.3	0.0
Total facility emissions	3.1	10.6	36.7	99.0	38.1	98.3	2.0	4.9	11.2	38.3

Several TAPs will also be released from the facility. Table 2 lists the estimates for toxics emitted above the screening emission levels specified in IDAPA 58.01.01.585 and 586. The ton-per-year emissions rates assume continuous operation of the emissions units. They are included for emissions inventory purposes only.

Table 2. TOXIC EMISSIONS ESTIMATES

Pollutant	Estimated Emissions		DEQ Screening Emission Level (lb/hr)
	(lb/hr)	(T/yr)	
Formaldehyde (annual average)	0.14	0.6	0.00051
Acetaldehyde	0.0058	0.02	0.003
Benzene	0.074	0.3	0.0008
Ammonia	20.6	82.4	1.2

Acetaldehyde, benzene, and formaldehyde are emitted as products of natural gas combustion. Ammonia is sprayed across the SCR catalyst to reduce NO_x emissions. As a normal part of this process, some ammonia passes beyond the catalyst and out the stack without being reacted; this is known as ammonia slip. Note that although the estimated emission rates of these TAPs are higher than the screening emission levels, when modeled in accordance with IDAPA 58.01.01.210.05, the ambient concentrations were found to be below the acceptable ambient concentrations for toxics listed in IDAPA 58.01.01.585, thus no further emissions reductions are required for air quality compliance purposes. as within 10 km of the facility.

5. REGULATORY ANALYSIS

Facility-Wide Applicable Requirements

5.1 Fugitive Particulate Matter - IDAPA 58.01.01.650-651

Permit Condition 2.1 states that all reasonable precautions shall be taken to prevent Particulate Matter from becoming airborne in accordance with IDAPA 58.01.01.650-651.

5.2 Compliance Demonstration

Permit Condition 2.2 states that the permittee is required to monitor and maintain records of the frequency and the methods used by the facility to reasonably control fugitive particulate emissions. The use of water or chemicals, applying dust suppressants, using control equipment, covering open-bodied trucks, paving roads or parking areas, and removing materials from streets are some examples listed in IDAPA 58.01.01.651.

Permit Condition 2.3 requires the permittee to maintain a record of all fugitive dust complaints received. In addition, the permittee is required to take appropriate corrective action as expeditiously as practicable after receipt of a valid complaint. The permittee is also required to maintain records that include the date each complaint was received, a description of the complaint, the permittee's assessment of the validity of the complaint, any corrective action taken, and the date the corrective action was taken.

Permit Condition 2.4 requires the permittee to conduct periodic inspections of the facility to ensure that the methods being used are reasonably controlling fugitive emissions, even if a complaint has not been received. The permittee is required to inspect potential sources of fugitive emissions during daylight hours and under normal operating conditions. If the permittee determines fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee is also required to maintain records of the results of each fugitive emission inspection.

Permit Conditions 2.3 and 2.4 require the permittee to take corrective action as expeditiously as practicable. In general, DEQ believes that taking corrective action within 24 hours of receiving a valid complaint, or determining that fugitive emissions are not being reasonably controlled, meets the intent of this requirement. However, it is understood that, depending on the circumstances, immediate action or a longer time period may be necessary.

5.3 Control of Odors - IDAPA 58.01.01.775-776

Permit Condition 2.5 and IDAPA 58.01.01.776 both state: "No person shall allow, suffer, cause or permit the emission of odorous gases, liquids or solids to the atmosphere in such quantities as to cause air pollution." This condition is currently considered federally enforceable until such time it is removed from the SIP, at which time it will be a state-only enforceable requirement.

5.4 Compliance Demonstration

Permit Condition 2.6 requires the permittee to maintain records of all odor complaints received. If the complaint has merit, the permittee is required to take appropriate corrective action as expeditiously as practicable. The records are required to contain the date each complaint was received, a description of the complaint, the permittee's assessment of the validity of the complaint, any corrective action taken, and the date the corrective action was taken.

Permit Condition 2.6 requires the permittee to take corrective action as expeditiously as practicable. In general, DEQ believes that taking corrective action within 24 hours of receipt of a valid odor complaint meets the intent of this requirement. However, it is understood that, depending on the circumstances, immediate action or a longer time period may be necessary.

5.5 Visible Emissions - IDAPA 58.01.01.625

Permit Condition 2.7 and IDAPA 58.01.01.625 state that "No person shall discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined . . ." by IDAPA 58.01.01.625. This provision does not apply when the presence of uncombined water, NO_x, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this rule.

5.6 Compliance Demonstration

Permit Condition 2.8 requires the permittee to conduct routine visible emissions inspections of the facility to ensure reasonable compliance with the visible emissions rule. The permittee is required to inspect potential sources during daylight hours and under normal operating conditions. The inspection consists of a see/no see evaluation for each potential source. If any visible emissions are present from any point of emission covered by this condition, the permittee must either take appropriate corrective action as expeditiously as practicable, or perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is determined to be greater than 20% for a period or periods aggregating more than three minutes in any 60-minute period, the permittee must take corrective action and report the exceedance in its semiannual monitoring/deviation report, annual compliance certification, and in accordance with the excess emissions rules in IDAPA 58.01.01.130-136. The permittee is also required to maintain records of the results of each visible emissions inspection and each opacity test when conducted. These records must include the date of each inspection, a description of the permittee's assessment of the conditions existing at the time visible emissions are present, any corrective action taken in response to the visible emissions, and the date corrective action was taken.

Should an emissions unit have a specific compliance demonstration method for visible emissions that differs from Facility-wide Condition 2.8, then the specific compliance demonstration method overrides the requirement of this condition. Facility-wide Condition 2.8 is intended for small sources that would generally not have any visible emissions.

Permit Condition 2.8 requires the permittee to take corrective action as expeditiously as practicable. In general, DEQ believes that taking corrective action within 24 hours of discovering visible emissions meets the intent of this requirement. However, it is understood that, depending on the circumstances, immediate action or a longer time period may be necessary.

5.7 Excess Emissions; Startup, Shutdown, Scheduled Maintenance, Safety Measures, Upset, and Breakdown - IDAPA58.01.01.130-136

Permit Condition 2.9 requires the permittee to comply with the requirements of IDAPA 58.01.01.130-136 for startup, shutdown, scheduled maintenance, safety measures, upset, and breakdowns. This section is fairly self-explanatory and no additional detail is necessary in this technical analysis. However, it should be noted that subsections 133.02, 133.03, 134.04, and 134.05 are not specifically included in the permit as applicable requirements. These provisions only apply if the permittee anticipates requesting consideration under subsection 131.02 to allow DEQ to determine if an enforcement action to impose penalties is warranted. Section 131.01 states ". . . The owner or operator of a facility or emissions unit generating excess emissions shall comply with Sections 131, 132, 133.01, 134.01, 134.02, 134.03, 135, and 136, as applicable. If the owner or operator anticipates requesting consideration under Subsection 131.02, then the owner or operator shall also comply with the applicable provisions of Subsections 133.02, 133.03, 134.04, and 134.05." Failure to prepare or file procedures pursuant to sections 133.02 and 134.04 is not a violation of the *Rules for the Control of Air Pollution in Idaho* in and of itself, as stated in subsections 133.03.a and 134.06.b. Therefore, since the permittee has the option to follow the procedures in subsections 133.02, 133.03, 134.04, and 134.05, and is not compelled to, the subsections are not considered applicable requirements for the purpose of this permit and are not included as such.

5.8 Compliance Demonstration

The compliance demonstration is contained within the text of Permit Condition 2.9. No further clarification is necessary here.

5.9 Test Methods

The reference test methods for each regulated air pollutant are listed in the permit. Any deviation from a reference test method should be approved by DEQ in writing in prior to conducting the test. Failure to obtain prior written approval may result in DEQ may determine the testing does not satisfy the testing requirements.

5.10 Monitoring and Recordkeeping

The permittee is required to retain all monitoring records and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application, as required by IDAPA 58.01.01.322.07.c. Though specific applicable requirements may have record retention times of less than five years, IDAPA 58.01.01.322.07.c requires the permittee to maintain all recorded data for a minimum of five years, which also satisfies those shorter record retention requirements.

5.11 Reports and Certifications

All periodic reports and certifications required by the permit shall be submitted within 30 days of the end of each specified reporting period to the appropriate DEQ regional office and EPA regional office as appropriate. The address for EPA's Acid Rain Division was included for reporting required by 40 CFR 72 through 78.

5.12 Fuel-Sulfur Content

The fuel-sulfur content requirements contained in IDAPA 58.01.01.728 apply only to fuels used in the diesel-fired standby electric generator and the diesel-fired fire pump. For details, refer to the section of this regulatory analysis which addresses these two sources.

5.13 Open Burning

All open burning shall be done in accordance with IDAPA 58.01.01.600-616.

5.14 Renovation/Demolition

The permittee shall comply with all applicable portions of 40 CFR 61, Subpart M, National Emission Standard for Asbestos when conducting any renovation or demolition activities at the facility.

5.15 Chemical Accident Prevention Provisions – 40 CFR 68

Any facility that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, must comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance is first present above a threshold quantity listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process. The threshold quantities for ammonia are 10,000 pounds for anhydrous ammonia and 20,000 pounds for aqueous ammonia with a concentration of 20% or greater, as listed in Table 1 of 40 CFR 68.130. The storage tank system used at Rathdrum Power will not exceed the threshold quantity based on the information presented on page 32 of the Tier I operating permit application, which is given as follows. "The concentration of ammonia in the aqueous ammonia is 29% by weight. The storage capacity of the tank is approximately 9000 gallons of aqueous ammonia with a density of 7.48 pounds per gallon. If the tank were filled to capacity, the amount of ammonia would be 19,523 pounds and therefore exempt from the requirements of 40 CFR 68 for Chemical Accident Prevention."

5.16 Recycling and Emission Reductions

The purpose of 40 CFR 82, Subpart F is to reduce emissions of Class I and Class II refrigerants to the lowest achievable level during the service, maintenance, repair, and disposal of appliances in accordance with Section 608 of the Clean Air Act. Subpart F applies to any person servicing, maintaining, or repairing appliances, except for motor vehicle emissions. Subpart F also applies to persons disposing of appliances, including motor vehicle air conditioners.

5.17 PTC General Provisions

General Provisions 2 and 6 from PTC No. P-020116 are applicable requirements that apply to all units regulated in the Tier I operating permit. In addition, PTC General Provision 3 is an applicable requirement that is not completely addressed by Tier I General Provision 14. In particular, PTC General Provision 3 allows DEQ to require stack emission testing in conformance with IDAPA 58.01.01.157 when deemed appropriate by the Director. Therefore, these applicable PTC requirements were included in the facility-wide section of the Tier I operating permit.

5.18 Fuel-Burning Equipment

The fuel-burning equipment requirements contained in IDAPA 58.01.01.676-677 do not apply to internal combustion engines (refer to the Department's *Draft Guidance for Fuel-burning Equipment Determination*, May 22, 2002). Specifically, these rules do not apply to the gas turbine, diesel standby generator, and the emergency fire pump. However, the rules do apply to the duct burners, the auxiliary boiler, and the fuel pre-heater. For details, refer to the specific sections of the permit and this regulatory analysis for each of these applicable emissions units.

5.19 NSPS (40 CFR 60) and NESHAPS (40 CFR 63)

The duct burners are subject to 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, because they were constructed after June 19, 1984 and have a heat input capacity greater than or equal to 100 MMBtu/hr. The gas turbine is subject to 40 CFR 60, Subpart GG, and the auxiliary boiler is subject to 40 CFR 60, Subpart Dc.

40 CFR 63, Subpart YYYY, was issued by the EPA as a final rule on March 5, 2004. Based on the TAPs PTE data in the Tier I application (pages 24-30), Rathdrum Power is not a "major source of HAP emissions" as defined by 40 CFR 63.6085(b). Therefore, the turbine is not subject to Subpart YYYY per 63.6085 because it is not located at a "major source of HAP emissions."

For all NSPS-affected units, the owner or operator shall comply with the requirements of the general provisions in 40 CFR 60, Subpart A. 40 CFR 60, Subpart A requirements that specify an action by the permittee have been included in Section 3 of the Tier I operating permit. However, all requirements concerning opacity and continuous monitoring were omitted since these are not applicable requirements for the facility.

40 CFR 60.4 states that Section 111(c) of the Clean Air Act directs the Administrator to delegate to each state, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such state. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate state agency of any state to which this authority has been delegated. However, note that 40 CFR 52 does not delegate authority for NSPS to the Idaho DEQ. Therefore, permit conditions requiring the facility to send DEQ copies of any NSPS submittals sent to EPA were added to the facility-wide permit conditions and to Section 3 of the Tier I permit under 40 CFR 60.4, as per IDAPA 58.01.01.322.08.

Included within the permit are copies of applicable requirements from 40 CFR 60 Subparts A, Db, and GG which were current as of the time of issuance of the permit. In the event of any discrepancies between this document, the Tier I permit, and the applicable federal regulations, the federal regulations shall govern.

6. REGULATORY ANALYSIS – EMISSIONS UNITS

Gas Turbine and Duct Burners

6.1 Emissions Unit Description

Refer to the descriptions in the permit and in Section 4 of the technical memorandum.

6.2 Permit Requirement – NO_x Emission Limits, PTC NO. P-020116, 10/12/04

The PTC includes both hourly and annual emission limits for the turbine with and without duct firing.

6.3 Compliance Demonstration

Installation of a NO_x continuous emission monitoring system (CEMS) is required by 40 CFR 75. The information from the CEMS will be used to continuously indicate the compliance status of the turbine and duct burner emissions with respect to the permit limit. Initial performance testing for NO_x was required in the PTC and additional testing may be requested at any time if necessary in accordance with PTC General Provision 3 (see facility-wide conditions of the Tier I operating permit) and 40 CFR 60.8(a). Note that the initial source test report was reviewed and approved by DEQ's Coeur d'Alene Regional Office on March 15, 2002. In addition, the CEMS is subject to testing and QA requirements in accordance with 40 CFR 60 and 75. In consideration of the results obtained from the initial source test, the CEMS, and from the CEMS QA requirements, additional source testing requirements for NO_x are not necessary in the Tier I operating permit.

The methods for determining compliance with the NO_x emission limits include the following: the turbine and the duct burners must be fired using natural gas exclusively; the hours of operation for the turbine and duct burners are limited; and the hours of operation are required to be monitored and recorded. Clarification was provided in the permit to show that the annual emission limit is measured on a consecutive 12-month basis, per IDAPA 58.01.01.322.01, since this was not directly stated in the PTC.

6.4 Permit Requirements – NO_x Emission Limit and Fuel Sulfur Content Limit, Gas Turbine NSPS, 40 CFR 60, Subpart GG

In accordance with 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, 40 CFR 60.332(a)(1), NO_x emissions must not exceed the following: STD = 0.0075(14.4/Y) + F. Where STD is the allowable NO_x emissions percent by volume at 15% oxygen on a dry basis, F is the NO_x emissions allowance for fuel-bound nitrogen, and Y is the manufacturer's heat input rate. In this case, STD equals 0.0109% or 109 ppmvd. In addition, fuel sulfur content must not exceed 0.8% by weight as per 40 CFR 60.333(b).

6.5 Compliance Demonstration

It is noted that this Tier I operating permit incorporates the final revision to 40 CFR Part 60 Subpart GG that was issued by the EPA as a final rule on July 8, 2004. The guaranteed NO_x emissions from the turbine (9 ppmvd) and with SCR control (3.4 ppmvd) are much less than the NO_x emission limit allowed by Subpart GG (109 ppmvd). Since the NO_x emission limits specified in the PTC are substantially lower, thus more restrictive, than the NSPS limit, the NSPS limit was not put in the PTC. However, in the Tier I operating permit, the NSPS limit was included because it is an applicable requirement per IDAPA 58.01.01.008.03.b. As long as the facility complies with the PTC requirements that limit NO_x emissions, and the fuel analysis requirements, compliance with the NSPS limit is reasonably assured. The sulfur and nitrogen content of the fuel must be monitored in accordance with 40 CFR 60.334(j) and (i), a copy of the May 24, 2001 EPA-approved Custom Fuel Monitoring Schedule is included in the Appendix, and permit conditions are established for these requirements in the monitoring and recordkeeping section of the permit. Rathdrum Power has also completed the initial NO_x and SO_2 performance testing requirements under 40 CFR 60.335 and 60.8, and the permit contains a requirement to perform additional testing under this standard "upon request of the Administrator" as specified in 40 CFR 60.8.

Another permit requirement to demonstrate compliance with the NO_x limit is to install, operate, and maintain the SCR system in good working order consistent with the manufacturer recommendations, including timely replacement of the catalyst. Excess emission reporting under Subpart GG is addressed under 60.334(j). For purposes of reporting excess NO_x emissions under 60.334, an exceedance shall be any emissions from the gas turbine stack that exceed 109 ppmvd at 15% oxygen.

6.6 Permit Requirement – NO_x Emission Limit, Duct Firing, 40 CFR 60, Subpart Db

40 CFR 60.40b(a) is applicable since the duct burner is a steam-generating unit with a heat input capacity greater than or equal to 100 MMBtu/hr. The following is a summary of the applicable requirements from Subpart Db:

- 40 CFR 60.40b(b) through 40 CFR 60.40b(h) are not applicable (n/a) to this source.

- 40 CFR 60.40b(i). Unless and until Subpart GG of Part 60 is revised to extend the applicability to steam generator units subject to Subpart Db, Subpart Db will continue to apply to combined cycle gas turbines that are capable of combusting more than 29 MW (100 MMBtu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam-generating unit are subject to Subpart Db. (The gas turbine emissions are subject to Subpart GG.)

- 40 CFR 60.40b(j). The facility's duct burners are not subject to Subpart D (Standards of Performance for Fossil Fuel-Fired Steam Generators, 40 CFR 60.40).

- 40 CFR 60.41b. The definitions given in 40 CFR 60.41b apply.

- 40 CFR 60.42b. The standards for SO_2 do not apply since the duct burners are fired exclusively with natural gas.

- 40 CFR 60.43b. The standards for particulate matter do not apply since the duct burners are fired exclusively with natural gas.

- 40 CFR 60.44b(a)(4)(i). Except as provided in 60.44b(l), since the initial performance test has been completed and the duct burners are required to combust natural gas exclusively, the owner or operator shall not cause to be discharged to the atmosphere any gasses that contain NO_x (expressed as NO_2) in excess of 86 ng/J (0.20 lb/MMBtu) of heat input for the duct burner. Also, refer to 60.44b(l) below, which sets the same emission limits.

  Compliance with this limit is also demonstrated by complying with the permit limits for combined NO_x emissions from the turbine and duct burners. As demonstrated in the PTC analysis, 4.5 ppmvd at 15% O_2 equates to 0.0166 lb/MMBtu, and this is well below the NSPS limit of 0.20 lb/MMBtu.

- 40 CFR 60.44b(b) through 60.44b(g). These requirements are not applicable since the duct burners are fired exclusively with natural gas.

- 40 CFR 60.44b(h). For purposes of paragraph (i) of this section, the NO_x standards under this section apply at all times, including periods of startup, shutdown, or malfunction.

- 40 CFR 60.44b(i). Compliance with the NO_x emission standards shall be determined on a 30-day rolling average basis since 60.44b(j and k) are not applicable. However, for duct burners used in combined cycle systems, a specific test is specified under 40 CFR 60.46b(f) which does not include a 30-day averaging procedure to determine compliance with the NO_x emission limit given by 40 CFR 60.44b(a)(4). Therefore, for duct burner performance testing at this facility, a 30-day rolling average is not used for compliance purposes; instead, the requirements of 40 CFR 60.46b(f) apply.

- 40 CFR 60.44b(j and k). These requirements are not applicable since the permit allows the annual capacity factor for natural gas to be greater than 10%.

- 40 CFR 60.44b(l)(1). For the duct burner, the initial performance test has been completed, the facility was constructed after July 9, 1997, and the duct burners are required to combust natural gas exclusively. The annual capacity factor for natural gas is greater than 10%, therefore, the owner or operator shall not cause to be discharged to the atmosphere any gases that contain NO_x (expressed as NO_2) in excess of 86 ng/J (0.20 lb/MMBtu) of heat input to the duct burner. 60.44b(l)(2) is not applicable since the duct burners do not operate at a low heat rate. See 60.44b(a)(4)(i) also.

6.7 Compliance Demonstration

Operating, monitoring, testing, recordkeeping, and reporting requirements to assure compliance with the Subpart Db emission limits are summarized as follows:

- 40 CFR 60.45b. The SO_2 testing procedures are n/a because the SO_2 emission standards do not apply to the duct burners.

- 40 CFR 60.46b(a, b, and d). The particulate matter compliance and performance test procedures are not applicable because the particulate matter emission standards do not apply to the duct burners.
- 40 CFR 60.46b(c) and (f). As noted above, compliance with the NO_x emission standards under 40 CFR 60.44b shall be determined through performance testing under 40 CFR 60.46b(f). Following the initial test, additional testing may be requested by the regulatory agency in accordance with 40 CFR 60.8. Note that the performance testing requirements under paragraphs 60.46b(g) and (h) are not applicable.
- 40 CFR 60.46b(e). This testing requirement is not applicable because the NO_x continuous monitoring system requirements under 60.48b are not applicable.
- 40 CFR 60.48b(a). Not applicable since the opacity standard does not apply.
- 40 CFR 60.48b(b) through (h). The NO_x monitoring requirements of 60.48b(b) through 60.48b(g) do not apply as specified by 60.48b(h).
- 40 CFR 60.48b(i). This regulation does not apply because 60.44b(j) or 60.44b(k) do not apply.
- 40 CFR 60.49b(a). The initial startup notification requirements of 40 CFR 60.49b(a)(1), (2), and (3) apply. DEQ received copies of appropriate notifications from Rathdrum Power in letters dated March 8, 2001; June 8, 2001; June 12, 2001; and July 20, 2001, which are located in the source file.
- 40 CFR 60.49b(b). The "initial" performance test reporting requirements of 40 CFR 60.49b(b) apply, however, the CEMS requirements do not apply per 60.48b(h). The requirements of 60.49b(b) have been met since DEQ received a copy of the initial performance tests which were conducted August 29 and 30, 2001 and on March 15, 2002, DEQ issued a letter indicating the tests complied with the PTC requirements.
- 40 CFR 60.49b(c). The requirements of 40 CFR 60.49b(c) do not apply because the NO_x monitoring requirements of 60.48b(b) through 60.48b(g) do not apply as specified by 60.48b(h).
- 40 CFR 60.49b(d). The recordkeeping requirements for the amount of fuel combusted and the annual capacity factor apply to this facility.
- 40 CFR 60.49b(e). This regulation doesn't apply since residual oil will not be combusted.
- 40 CFR 60.49b(f). This regulation doesn't apply since the opacity standard doesn't apply.
- 40 CFR 60.49b(g). This regulation doesn't apply because the NO_x monitoring requirements of 60.48b(b) through 60.48b(g) do not apply as specified by 60.48b(h).
- 40 CFR 60.49b(h). This regulation doesn't apply. In particular: 60.49b(h)(2) applies; 60.49b(h)(3) doesn't apply since the particulate matter standard does not apply; and 60.49b(h)(4) doesn't apply since the NO_x monitoring requirements of 60.48b(b) through 60.48b(g) do not apply as specified by 60.48b(h).60.48b(g).
- 40 CFR 60.49b(i). This regulation doesn't apply because the NO_x monitoring requirements of 60.48b(b) through 60.48b(g) do not apply as specified by 60.48b(h).
- 40 CFR 60.49b(j), (k), (l), (m), and (n). These are not applicable since the source is not subject to the SO_2 requirements under 60.42b.
- 40 CFR 60.49b(o) requires that all records required under this section be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. Note that the facility-wide permit conditions require all records to be maintained for at least five years; therefore, for consistency the five-year requirement was put into this section of the permit.
- 40 CFR 60.49b(p), (q) and (r). These are not applicable since 60.44b(j) and (k) do not apply.

- 40 CFR 60.49b(s), (t) and (u). These are not applicable since they are facility-specific standards for other facilities.
- 40 CFR 60.49b(v) and (w). These reporting requirements don't apply because 60.48b(h, i, j, k, and l) do not apply.

6.8 Permit Requirement – CO, PM_{10}, SO_2, and VOC Emissions Limits, PTC No. P-020116, 10/12/04

Emission limits included in the PTC for this facility are applicable requirements that must be included in the Tier I operating permit.

6.9 Compliance Demonstration

Compliance with the SO_2 and VOC emission limits for the gas turbine with duct firing shall be demonstrated by performing calculations using the emission factors as used in the PTC application analysis (or equivalent factors) and the hours of operation for each unit at the maximum firing rates. Compliance has already been demonstrated in the PTC technical analysis using the allowable fuel (natural gas) and the allowable hours of operation, which were established as permit conditions in the PTC. Therefore, ongoing compliance with the SO_2 and VOC emission limits for the gas turbine are demonstrated as long as each unit burns only natural gas and the hours of operation do not exceed the corresponding operating limits established as permit conditions in the PTC and the Tier I permit. Specifically, the units are in compliance as long as the gas turbine operations do not exceed 8000 hr/yr, the duct firing operations do not exceed 2000 hr/yr, and the units fire natural gas exclusively. Also, the permit includes requirements to monitor and record the hours of operation on a monthly basis.

Compliance with the CO emission limits for the gas turbine with duct firing may be demonstrated by performing calculations using the emission factor determined from the most recent stack test for CO and the hours of operation for each unit at the maximum firing rates. Stack tests for CO are required at least annually. Compliance was initially demonstrated in the PTC technical analysis using the allowable fuel (natural gas) and the allowable hours of operation, which were established as permit conditions in the PTC. Alternatively, compliance with the CO emissions limits may be determined by performing monitoring and recordkeeping using a CEMS. However, before the CEMS data can be accepted for this purpose, the permittee must demonstrate that adequate QA procedures have been performed to ensure reliable data was obtained. Another permit requirement to demonstrate compliance with the CO emission limit is to install, operate, and maintain an Oxidation Catalyst system in good working order consistent with manufacturer recommendations, including timely replacement of the catalyst.

Compliance with the PM_{10} emission limits for the turbine with duct firing may be demonstrated by performing calculations using the emission factors derived from the most recent PM_{10} source test and the hours of operation for each unit at the maximum firing rates. Stack tests for PM_{10} are required at least once each permit term (i.e., every five years) and more often depending on how close the test results are to the PM_{10} emission rate limits in the permit. Once compliance with the emission rate limits has been demonstrated through testing, ongoing compliance may be demonstrated by firing only natural gas and not exceeding the hours of operation limits in the Tier I permit. For this purpose, the permit includes requirements to record the hours of operation on a monthly basis.

6.10 Permit Requirement – TAP Emissions Limits, PTC No. P-020116, 10/12/04

Emission limits included in the PTC for this facility are applicable requirements that must be included in the Tier I operating permit.

6.11 Compliance Demonstration

Compliance with all TAP emission limits except ammonia for the gas turbine with duct firing shall be demonstrated by performing calculations using the emission factors as used in the PTC application analysis (or equivalent factors) and the hours of operation for each unit at the maximum firing rates. Compliance has already been demonstrated in the PTC technical analysis using the allowable fuel (natural gas), maximum firing rates, and the allowable hours of operation, which were established as permit conditions in the PTC. Therefore, compliance with these TAP emission limits for the gas turbine and duct burners is demonstrated as long as each unit burns only natural gas and the hours of operation do not exceed the corresponding operating limits established as permit conditions in the PTC and the Tier I permit. Specifically, the emission units are in compliance as long as the gas turbine operations do not exceed 8000 hr/yr, the duct firing operations do not exceed 2000 hr/yr, and the units fire natural gas exclusively. The permit also includes a requirement to record the hours of operation on a monthly basis. Compliance with the ammonia emissions limits is determined by performing monitoring and recordkeeping using either a CEMS or through performance testing. The PTC issued in October, 1999 allowed for removal of the CEMS after two years, however, it also included a requirement for annual performance testing for ammonia. The system may be removed after two years, however, if source testing results are more than 80% of the ammonia emission limit, then DEQ may require the CEMS to be re-installed.

Related data collection requirements were reviewed to set a minimum data collection frequency for the ammonia monitor. The NSPS requirement for continuous monitor data collection is contained in 40 CFR 60.13(e)(2) and states, "all continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. 40 CFR Part 75 requirements for continuous monitor data collection are contained in 75.10(d)(1) as follows:

> (1) The owner or operator shall ensure that each continuous emission monitoring system is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, CO_2 concentration, O_2 concentration, CO_2 mass emissions (if applicable), NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to §75.21 and appendix B of this part, or backups of data from the data acquisition and handling system, or recertification, pursuant to §75.20. The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.

Annual emissions will be determined for each rolling 12-month period.

For quality assurance purposes, the relative accuracy requirements in 40 CFR 60, Performance Specification 2, are not directly applicable to the ammonia CEMS but will be used because the ammonia CEMS consists of a modified NO_x analyzer. The emissions are measured in the sub-one ppm range, so meeting the 20% relative accuracy standard is not easy to do. DEQ has decided for this source that obtaining a mean difference of less than 2 ppm between the reference method and the CEMS analyzer is acceptable even if the relative accuracy is greater than 20% because the range is so small. For example, the 2003 ammonia Relative Accuracy test Audit (RATA) had a relative accuracy of 33% while the mean difference between the reference method and CEMS analyzer was only 0.2 ppm. The daily calibration results shall be acceptable if the response is ± 2 ppm of the reference gas. This is ± 20% of the span. Rathdrum Power proposed that a daily calibration be acceptable if the results were ± 5 ppm of the reference gas in accordance with 40 CFR 75, Appendix A, 3.1(b), for monitors with a span < 200 ppm. This was not accepted because the span of the monitor is only 10 ppm, and it did not seem reasonable to have an acceptable daily calibration error of ± 50% of the span.

6.12 Permit Requirement – Fuel-Burning Equipment, Duct Burners, IDAPA 58.01.01.676

The duct burners were installed in 2001; therefore, these units are subject to the particulate matter standard for new fuel-burning equipment. The grain-loading standard for natural gas combustion is 0.015 grains per dry standard cubic foot of effluent gas corrected to 3% oxygen by volume.

6.13 Compliance Demonstration

It is reasonable to assume that compliance with the particulate matter standard is assured provided that only natural gas is combusted and the duct burners are maintained in good working order and operated per manufacturer recommendations. According to 40 CFR 60, Appendix A, Method 19, Table 19-1, approximately 8,710 dscf of flue gas at standard conditions (68°F, 29.92 inches of Hg) is created per million British thermal units of natural gas. This data is used in the following steps to demonstrate that particulate emissions from the combustion of natural gas will always be less than the particulate matter standard of 0.015 grains per dry standard cubic foot.

Correct the flue gas volume as follows:

1) Altitude correction, IDAPA 58.01.01.680. (The altitude of Rathdrum is 2,200 feet).

   Subtract 0.10 x 22.0 = 2.20 inches Hg from standard atmospheric pressure at sea level.

   29.92 inches Hg – 2.20 inches Hg = 27.72 inches Hg

2) The gas volume corrected to altitude and 3% oxygen.

   Using the Ideal Gas Law and knowing that n, R, and T will be the same,

$$V_2 = \frac{P_1 V_1}{P_2} \tag{6.1}$$

   where,

   V_2 = the gas volume corrected for altitude,
   V_1 = the known gas volume (8,710 dscf),
   P_1 = the pressure of the known gas volume (29.92 inches Hg)
   P_2 = the pressure of the corrected gas volume (27.72 inches Hg).

   The altitude corrected volume (V_2) of the flue gas is 9,401 dscf.

   For 3% oxygen:

   Using a standard correction ratio as presented in 40 CFR 60, Appendix A, Method 19,

$$F_2 = F_1 \times \frac{20.9}{20.9 - 3.0} \tag{6.2}$$

   where,

F_2 = the gas volume corrected to 3% oxygen,
F_1 = the altitude corrected flue gas volume (9401 dscf) calculated as V_2 above.

The oxygen and altitude corrected volume (F_2) of the flue gas is 10,980 dscf per million British thermal units of natural gas.

3) Determine the volume of flue gas created by the combustion of one million cubic feet of natural gas as follows:

$$10^6 \text{ feet}^3 \times 1{,}050 \text{ Btu/feet}^3 \times 10{,}980 \text{ dscf}/10^6 \text{ Btu} = 11.5 \times 10^6 \text{ dscf} \quad (6.3)$$

4) Determine the amount of particulate matter (PM) created by the combustion of one million cubic feet of natural gas (note: from Table 3.2 of the 10/29/99 PTC technical memorandum appendix, duct burner PM = 1.7 lb/hr at the maximum firing rate of 230 MMBtu/hr):

$$1.7 \text{ lb/hr} \div 230 \text{ MMBtu/hr} \times 1{,}050 \text{ Btu/feet}^3 = 7.8 \text{ lb/MMscf} \quad (6.4)$$

5) Determine the grain loading per cubic foot of flue gas as follows:

$$7.8 \text{ lb PM} \times 7{,}000 \text{ gr/lb} \div 11.5 \times 10^6 \text{ dscf} = 0.0047 \text{ gr/dscf} < 0.015 \text{ gr/dscf} \quad (6.5)$$

The emission factor used represents a conservative estimate. Even a conservative estimate of emissions from natural gas combustion results in an approximated grain loading well below the standard of 0.015 gr/dscf. Therefore, as long as the permittee is in compliance with the permit condition requiring the exclusive use of natural gas, the permittee is in compliance with the grain-loading standard.

6.14 Visible Emissions - IDAPA 58.01.01.625

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity. This provision does not apply when the presence of uncombined water, NO_x, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this rule.

6.15 Compliance Demonstration

A visible emissions evaluation is required for each stack at the facility, including the gas turbine stack, on a monthly basis and in accordance with IDAPA 58.01.01.625. The compliance determination method for IDAPA 58.01.01.625 is Facility-wide Condition 2.8.

6.16 Permit Requirement – NO_x Monitoring, Acid Rain Program, 40 CFR 75

Rathdrum Power is an affected unit under 40 CFR 72.6(a)(3)(i) and must comply with the operating, monitoring, and recordkeeping requirements of 40 CFR 75.

6.17 Compliance Demonstration

Operating, monitoring, and recordkeeping requirements that demonstrate compliance with the federal Acid Rain Program are provided in 40 CFR 75. Note that a copy of the monitoring plan required by 40 CFR 75.62 was received by DEQ May 31, 2001 and is located in the source test folder in the source file. The requirements have been included in the Tier I operating permit. Also see the Acid Rain Permit section of this document below.

6.18 PTC Requirement – Ammonia Feed Rate Monitoring, PTC Condition 3.2, PTC No. P-020116, 10/12/04

The PTC contains a requirement to maintain records for a minimum of two years.

6.19 Compliance Demonstration

IDAPA 58.01.01.322.07.c requires records be maintained for at least five years, therefore, the corresponding permit condition in the Tier I operating permit requires the records to be maintained at least five years.

6.20 PTC Requirement – Excess Emissions, PTC Conditions 4.5, PTC No. P-020116, 10/12/04

The PTC contains excess emission requirements regarding NSPS, Subpart Db. For purposes of reporting excess NO_x emissions under 60.334, an exceedance shall be any emissions from the gas turbine stack that exceed 109 ppmvd at 15% oxygen.

6.21 Compliance Demonstration

In the event that an excess emissions event occurs under Subpart GG, compliance is demonstrated by following the reporting requirements under 60.334(c).

6.22 PTC Requirement – Initial Startup Notification, 40 CFR 60.49b(a)

The PTC contains notification requirements which were necessary following the initial startup of the facility.

6.23 Compliance Demonstration

This requirement was not included in the Tier I operating permit because it was a one time requirement. The EPA and DEQ received appropriate notifications from Rathdrum Power in letters dated March 8, June 8, June 12, and July 20, 2001. Copies are located in the source file. Note that these notifications include information for all permitted units, not just the gas turbine.

6.24 Federal Requirement – Compliance Assurance Monitoring (CAM), 40 CFR 64

40 CFR 64 establishes criteria that define what monitoring should be conducted by a source owner or operator to provide a reasonable assurance there is compliance with emission limits and standards in order to certify compliance under the Title V operating permit program. Since Rathdrum Power in not a major source, these regulations do not apply, as per 40 CFR 64.2.

6.25 Compliance Demonstration

None required since this is not an applicable requirement for Rathdrum Power.

Auxiliary Boiler And Fuel Heater

6.26 Emissions Unit Description

Refer to the emissions unit descriptions provided in the permit.

6.27 Permit Requirement – Hourly and Annual Emissions Limits for CO, NO_x, PM_{10}, and SO_2, PTC No. P-020116, 10/12/04

Emission limits included in the PTC for this facility are applicable requirements that must be included in the Tier I operating permit.

6.28 Compliance Demonstration

Compliance with the emission limits for these two units shall be demonstrated by performing calculations using EPA emission factors and the hours of operation for each unit. Compliance has already been demonstrated in the PTC technical analysis using the allowable fuel (natural gas) and the allowable hours of operation, which were established as permit conditions in the PTC. Therefore, compliance with the emission limits for the auxiliary boiler and fuel heater are demonstrated as long as each of these units burn only natural gas and the hours of operation do not exceed the corresponding operating limits established in the PTC and Tier I permit. Specifically, the units are in compliance as long as the auxiliary boiler operations do not exceed 500 hr/yr and the fuel heater operations do not exceed 8000 hr/yr. Compliance is further demonstrated by permit requirements to record the hours of operation on a monthly basis.

6.29 Permit Requirement – Visible Emissions, IDAPA 58.01.01.625

The requirement that emissions may not exceed 20% opacity for more than three minutes in any 60-minute period applies to both the auxiliary boiler and fuel heater stacks.

6.30 Compliance Demonstration

Compliance with the visible emissions standard for these two emission units is demonstrated by complying with Permit Condition 2.8.

6.31 Permit Requirement – Fuel Burning Equipment, IDAPA 58.01.01.676

The auxiliary boiler and fuel heater were installed in July 2001; therefore, these units are subject to the particulate matter standard for new fuel-burning equipment. The grain-loading standard for natural gas combustion is 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume, per IDAPA 58.01.01.675.

6.32 Compliance Demonstration

It is reasonable to assume that compliance with the particulate matter standard is assured provided that only natural gas is combusted and the units are maintained in good working order and operated per manufacturer recommendations. According to AP-42, Section 1.4, July 1998, the burners would emit 7.6 pounds of particulate per million cubic feet of natural gas combusted. Also, according to 40 CFR 60, Appendix A, Method 19, Table 19-1, approximately 8,710 dscf of flue gas at standard conditions (68° F, 29.92 inches of Hg) is created per million British thermal units of natural gas. This data is used in the following steps to demonstrate that particulate emissions from the combustion of natural gas will always be less than the particulate matter standard of 0.015 gr/dscf.

Correct the flue gas volume as follows:

1) Altitude correction, IDAPA 58.01.01.680. (The altitude of Rathdrum is 2,200 feet).

   Subtract 0.10 x 22.0 = 2.20 inches Hg from standard atmospheric pressure at sea level.
   29.92 inches Hg – 2.20 inches Hg = 27.72 inches Hg

2) Using the Ideal Gas Law and knowing that n, R, and T will be the same,

$$V_2 = \frac{P_1 V_1}{P_2} \tag{6.6}$$

where,

V_2 = the gas volume corrected for altitude,
V_1 = the known gas volume (8,710 dscf),
P_1 = the pressure of the known gas volume (29.92 inches Hg)
P_2 = the pressure of the corrected gas volume (27.72 inches Hg).

The altitude corrected volume (V_2) of the flue gas is 9401 dscf.

For 3% oxygen:

Using a standard correction ratio as presented in 40 CFR 60, Appendix A, Method 19,

$$F_2 = F_1 \times \frac{20.9}{20.9 - 3.0} \tag{6.7}$$

where,

F_2 = the gas volume corrected to 3% oxygen,
F_1 = the altitude corrected flue gas volume (9,401 dscf) as calculated in Equation 5.1.

The oxygen and altitude corrected volume (F_2) of the flue gas is 10,980 dscf per million British thermal units of natural gas.

3) Determine the volume of flue gas created by the combustion of one million cubic feet of natural gas as follows:

$$10^6 \text{ feet}^3 \times 1{,}050 \text{ Btu/feet}^3 \times 10{,}980 \text{ dscf}/10^6 \text{ Btu} = 11.5 \times 10^6 \text{ dscf} \tag{6.8}$$

4) Determine the grain loading per cubic foot of flue gas as follows:

$$7.6 \text{ lb PM} \times 7{,}000 \text{ gr/lb} \div 11.5 \times 10^6 \text{ dscf} = 0.0046 \text{ gr/dscf} < 0.015 \text{ gr/dscf} \tag{6.9}$$

Emissions factors given in AP-42 are generally accepted as conservative estimates. Even a conservative estimate of emissions from natural gas combustion results in an approximated grain loading well below the standard of 0.015 gr/dscf. Therefore, as long as the permittee is in compliance with the permit condition requiring the exclusive use of natural gas, the permittee is in compliance with the grain-loading standard.

6.33 Permit Requirement – NSPS Subpart Dc, 40 CFR 60.48c(a, g and i)

The auxiliary boiler is subject to 40 CFR 60, Subpart Dc since it was constructed after June 9, 1989, and the maximum heat input capacity is between 10 and 100 MMBtu/hr. Note that the initial notification requirements of 60.48c(a) are also applicable.

6.34 Compliance Demonstration

The permittee is required to keep records of daily fuel consumption as required by 60.48c(g). The records must be maintained for at least five years, consistent with the recordkeeping requirements specified in the Tier I facility-wide permit conditions that exceed the two-year retention period specified by 60.48c(i).

The initial notification requirements of 60.48c(a) were previously complied with. DEQ received appropriate notifications from Rathdrum Power in letters dated March 8, June 8, June 12, and July 20, 2001. Copies are located in the source file. Note that these notifications include all permitted units, not just the gas turbine.

Diesel Generator And Fire Pump

6.35 Emissions Unit Description

Refer to the emissions unit description provided in the permit.

6.36 Permit Requirement – Visible Emissions, IDAPA 58.01.01.625

The requirement that emissions may not exceed 20% opacity for more than three minutes in any 60-minute period applies to both diesel engine stacks.

6.37 Compliance Demonstration

Compliance with the visible emissions standard for these two emission units is demonstrated by complying with Permit Condition 2.8.

6.38 Permit Requirement – Hours of Operation, PTC No. P-020116, 10/12/04

The restrictions on hours of operation for the diesel generator and fire pump were included in the Tier I operating permit because this was a permit condition in the facility's PTC. This permit condition was included in the PTC because a restriction on the hours of operation was used in the modeling analysis performed for the PTC. In the PTC analysis, it was demonstrated that emissions resulting from this amount of operation would be compliant with the NAAQS and TAPS requirements.

6.39 Compliance Demonstration

Compliance is demonstrated by complying with the monitoring and recordkeeping requirements included in the permit for hours of operation. The permittee must monitor the hours of operation for each source on a monthly and rolling 12-month basis.

6.40 Permit Requirement – Fuel Sulfur Content, IDAPA 58.01.01.728

No person shall sell, distribute, use, or make available for use any distillate fuel oil containing more than the percentages of sulfur allowed by the *Rules for the Control of Air Pollution in Idaho.*

6.41 Compliance Demonstration

For each load of fuel received at the facility, the permittee is required to maintain copies of documentation received from the supplier which shows the sulfur content of the distillate fuel.

7. TITLE IV ACID RAIN PERMIT

7.1 Emissions Unit Description

Refer to the turbine and duct burner descriptions provided in the permit. Rathdrum Power is an affected unit under 40 CFR 72.6(a)(3)(i); therefore, is subject to the Acid Rain Program.

7.2 Permit Requirement – Acid Rain Permit Contents, 40 CFR 72.50

The requirements for an Acid Rain Permit are listed in 40 CFR 72.50. The permit must contain the following: 1) all elements required for a complete Acid Rain permit application under 72.31, as approved or adjusted by the permitting authority; 2) the applicable Acid Rain emissions limitation for SO_2; 3) the applicable Acid Rain emissions limitation for NO_x; and 4) each Acid Rain permit is deemed to incorporate the definitions of terms under 72.2.

7.3 Compliance Demonstration

Compliance requirements are listed in the Acid Rain Permit application as included in the Tier I operating permit. Compliance with these requirements will assure compliance with the Acid Rain Program requirements.

7.4 Permit Requirement – SO_2 and NO_x Allowances, 40 CFR 73.2, 76.1

Rathdrum Power is subject to the provisions of Part 73 for SO_2 since it is an affected source pursuant to 72.6(a)(3)(i). The facility doe not contain an affected source pursuant to 76.1since coal is not used for fuel, therefore, it is not subject to the provisions of Part 76 for NO_x.

7.5 Compliance Demonstration

Compliance with the requirements of Part 73 is accomplished by complying with the requirements listed in the Acid Rain Permit application. The application requirements are included as part of the Acid Rain Permit as required by 72.50(a)(1). Compliance with the application requirements will assure compliance with the Acid Rain Program requirements.

8. INSIGNIFICANT ACTIVITIES

Insignificant activities described by the source in accordance with IDAPA 58.01.01.317 are listed below.

Table 3. INSIGNIFICANT ACTIVITIES

Emissions Unit	Description	Insignificant Activities IDAPA 58.01.01.317.01...
IEU-1	Turbine lube oil tank and vent. This category includes all storage tanks, reservoirs, and pumping and handling equipment of any size, limited to soaps, lubricants, lubricating oil, treater oil, hydraulic fluid, vegetable oil, grease, animal fat, aqueous salt solutions, or other materials and processes using appropriate lids and covers where there is no generation of objectionable odor or airborne particulate matter.	317.01(a)(i)(4)
IEU-2	Cooling towers	317.01(a)(i)(107)
IEU-3	Welding operations using not more than 1 T/day of welding rod	317.01(b)(i)(9)
IEU-4	Storage tanks – operation loading and unloading of volatile organic compound storage tanks, 10,000-gallon capacity or less, with lids or other appropriate closure, vapor pressure not greater than 80mm Hg at 21°F.	317.01(b)(i)(3)

9. ALTERNATIVE OPERATING SCENARIOS

No alternative operating scenarios were proposed in the permit application.

10. TRADING SCENARIOS

No trading scenarios were proposed in the permit application.

11. COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION

11.1 Compliance Plan

Rathdrum Power has certified compliance with all applicable requirements. No compliance plan was submitted.

11.2 Compliance Certification

Rathdrum Power is required to periodically certify compliance in accordance with General Provision 21 of the Tier I operating permit.

12. ACID RAIN PERMIT

Rathdrum Power is subject to the acid rain permitting requirements of 40 CFR 72 through 75. The provisions of 40 CFR 76 regarding NO_x emissions do not apply; however, the facility is required to obtain SO_2 allowances in accordance with 40 CFR 72.9(c). The facility does not have a NO_x or SO_2 emission limit through these regulations. The substance of the regulation which applies to this facility is the requirement to monitor emissions and report the results. Refer to the regulatory analysis section of this memo for additional information. The acid rain portion of the permit was drafted in the form of the EPA model permit based upon 40 CFR 72 and information previously provided by Bob Miller, EPA Acid Rain Division, Washington D.C. The substance of the acid rain permit for Rathdrum Power is that the company must comply with the requirements listed on the EPA Phase II application.

13. AIRS DATABASE

Note that the overall AIRS classification for this facility needs to be changed from A2 to SM. Also, this is a SM-80 facility for purposes of applying EPA's April 2001 draft Compliance Monitoring Strategy (see facility classification for details) and it is subject to a full compliance evaluation at least once every five years. Additional information is provided as follows:

AIRS/AFS FACILITY-WIDE CLASSIFICATION DATA ENTRY FORM

AIR PROGRAM / POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	TITLE V	AREA CLASSIFICATION A – Attainment U – Unclassifiable N – Nonattainment
SO_2	B					B	U
NO_x	SM	SM	NO_x for both subparts indicated below			SM	U
CO	SM	SM				SM	U
PM10	B					B	U
PT (Particulate)	B					B	U
VOC	B					B	U
THAP (Total HAPs)	B					B	
			APPLICABLE SUBPART				
			Db, GG				

AIRS/AFS Classification Codes:

- A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For NESHAP only, class "A" is applied to each pollutant that is below the 10 T/yr threshold, but which contributes to a plant total in excess of 25 T/yr of all NESHAP pollutants.
- SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.
- B = Actual and potential emissions below all applicable major source thresholds.
- C = Class is unknown.
- ND = Major source thresholds are not defined (e.g., radionuclides).

14. REGISTRATION FEES

Rathdrum Power is not a major facility as defined in IDAPA 58.01.01.008.10; therefore, registration and registration fees, in accordance with IDAPA 58.01.01.387, do not apply.

15. RECOMMENDATION

Based on the Tier I application and review of federal regulations and state rules, staff recommends DEQ issue final Tier I operating permit No. 055-00045 to Rathdrum Power LLC for the electric power generation facility located near Rathdrum. The public comment process and the required EPA 45-day review are complete, and the project does not involve PSD requirements.

BR/KH/sd G:\Air Quality\Stationary Source\SS Ltd\T1\Rathdrum Power\Final\T1-020108 Final SB.doc

APPENDIX

Rathdrum Power LLC, Rathdrum

T1-0020108

5/24/01 Letter From EPA Region 10 To DEQ's Coeur d'Alene Regional Office

Please

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

AFS/SF

RECEIVED
JUN 04 2001
DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE AQ PROGRAM

MAY 24 2001

RECEIVED
MAY 30 2001
IDHW-DEQ
Coeur d'Alene Field Office

Reply To
Attn Of: OAQ-107

Mr. Tracy L. Patterson
Air Quality Manager
Cogentrix Energy, Inc.
P.O. Box 995
Rathdrum, ID 83858

Re: Custom Fuel Monitoring Schedule
New Source Performance Standards, Subpart GG

Dear Mr. Patterson:

The United States Environmental Protection Agency (EPA) has received a request dated November 6, 2000 for a custom fuel monitoring schedule for the Cogentrix combined cycle turbine located in Rathdrum, Idaho. Pertaining to this request, EPA has also received additional information from Cogentrix dated May 10, 2001. As stated below, EPA approves of this request for a custom fuel monitoring schedule.

EPA understands that Cogentrix will operate a gas-fired combined cycle turbine in Rathdrum, Idaho, subject to the Acid Rain Program, and must comply with the monitoring and reporting requirements of 40 C.F.R. Part 75. EPA also understands that Congentrix will be installing a continuous emission monitoring system (CEMS) to monitor and record the nitrogen oxides emissions from this unit, as required by 40 C.F.R. Part 75. This gas-fired turbine is also subject to New Source Performance Standards (NSPS), Subpart GG regulations. The attached custom fuel monitoring schedule is applicable to the Cogentrix turbine located in Rathdrum, Idaho, identified by: General Electric model PG7241FA, with serial number 297468, rated for a nominal output of 164,700 Kw with heat input of 1,518 MMBtu per hour, and firing exclusively pipeline natural gas. EPA approves of Congentrix's request for nitrogen monitoring waiver, and an alternate sulfur monitoring schedule as described in the attached Alternate Monitoring Plan Requirements.

This letter does not alter any of the other requirements of NSPS Subparts A and GG which may apply to the facility. All reports should be addressed to this office. If you have any questions regarding this letter, please do not hesitate to contact Mr. Kai Hon Shum at (206) 553-2117.

Sincerely,

Harold Scott for

Douglas E. Hardesty, Manager
Federal and Delegated Air Programs Unit

Enclosure

cc: Tom Harman (IDEQ)

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U.S. Environmental Protection Agency Region 10
Alternate Monitoring Plan Requirements

Applicability

This alternative monitoring schedule applies to one stationary gas turbine operated by Cogentrix Energy, Inc., located in Rathdrum, Idaho, as described below:

General Electric turbine model PG7241FA, serial number 297468, rated for nominal output of 164,700 kilowatts with a heat input of 1,518 MMBtu per hour, and firing exclusively on pipeline natural gas.

This alternative monitoring plan applies to the above noted turbine firing exclusively on pipeline natural gas as defined by 40 C.F.R.§72.2 , and does not alter any of the other requirements of NSPS Subparts A and GG which may apply to the facility. In the event that this turbine would no longer have to comply with the Acid Rain Program, then this alternative monitoring plan would be void, and Cogentrix would have to comply with the monitoring requirements specified in NSPS Subpart GG.

Nitrogen Monitoring

Nitrogen monitoring shall be waived for pipeline natural gas.

Sulfur Monitoring

Cogentrix shall comply with documentation requirements that the fuel is pipeline natural gas in §2.3.1.4, and the procedures for sulfur content determination in §2.3.3.1 of Appendix D to 40 C.F.R. Part 75.

Reporting

Cogentrix shall provide annual reports to EPA Region 10 with documentation that the fuel is pipeline natural gas as specified in §2.3.1.4, and sulfur content determination specified in §2.3.3.1 of Appendix D to 40 C.F.R. Part 75.

Approved this 24th day of May, 2001

Harold Scott for

Douglas E. Hardesty, Manager
Federal and Delegated Air Programs Unit
Office of Air Quality